NOVA SCOTIA ELECTRIC MARKETPLACE GOVERNANCE COMMITTEE

ISSUES PAPER #2

TRANSMISSION ISSUES

July 12, 2002

THIS ISSUES PAPER IS THE WORK PRODUCT OF NAVIGANT CONSULTING LTD. AND BEEN PREPARED ON BEHALF OF THE ELECTRIC MARKETPLACE GOVERNANCE COMMITTEE (COMMITTEE), BUT DOES NOT NECESSARILY REFLECT THE VIEWS OF THE COMMITTEE.

Navigant Consulting Ltd.
180 Bloor Street West
Toronto, Ontario
M5S 2V6

103-04487/

Table of Contents

1 INTRODUCTION 1

2 OVERVIEW OF TRANSMISSION ISSUES 1

3 TRANSMISSION INFRASTRUCTURE REVIEW 2

4 ALLOCATING THE FIXED COSTS OF THE TRANSMISSION SYSTEM 3

4.1 Transmission Facilities Covered Under the Tariff 4
4.2 Transmission Operation and Maintenance Costs Included in the Tariff 6
4.3 Billing Determinants for Fixed Transmission Cost Allocation 6
4.4 OATT Rate for Nova Scotia and Exports 9
4.5 Cost Allocation OATT to Export Customers 10
4.6 Unbundling Transmission Cost for Existing Bundled Service Customers 10

5 APPROACH TO CONGESTION MANAGEMENT 11

5.1 Treatment of External Transactions 11
5.2 Long Term Congestion Management Choices 12

6 TREATMENT OF LOSSES 13

7 RIGHTS CONVEYED 14

8 TREATMENT OF ANCILLARY SERVICES 14

1 INTRODUCTION

Designing a new electric market structure is a significant endeavor, requiring careful consideration of a large portfolio of broad and detailed market design issues. Depending on the market envisioned changes in the market structure to accommodate an Open Access Transmission Tariff (OATT) may be minor or sweeping and can range from changing as few practices as possible to implement the OATT to broad and overall changes in asset ownership, governance, and overall market concept.

As part of the measured, stepwise approach to adopting electricity market reforms identified in the Government Policy Paper, this paper focuses on implementing an Open Access Transmission Tariff (OATT) compatible with the FERC Order 888/889 structure without broad or sweeping market reforms. Focusing on issues associated with implementing an OATT suitable for providing open access to Nova Scotia's six eligible municipal utilities within a short time frame, this paper identifies some of the higher level transmission issues that at a minimum must be resolved to implement such a tariff, decisions that must be made to implement such a tariff, alternative approaches to be considered and the pros and cons of each alternative. It is anticipated that discussion in the committee process will help to define the alternatives favored by the Committee. While alternatives for further market restructuring are also briefly identified, further discussion of more fundamental market changes will be included in later issue papers in instances where the Committee believes it to be appropriate.

2 OVERVIEW OF TRANSMISSION ISSUES

The transmission system is the essential channel for the sale of electricity. Without transmission, neither open access nor electricity competition can occur. The conditions of access to the transmission system are therefore crucial to the functioning of any electricity market, and for open access market design. Typical design criteria include transmission accessibility as well as equitable and non-discriminatory pricing, so that potential wholesale users and or competitors are not arbitrarily precluded from the market by the conditions of transmission access or the administration of the transmission tariff. Transmission pricing is generally designed so it does not favor some market participants arbitrarily over others and to prevent artificial barriers to the construction of economic new transmission. Meeting these simple

conditions can be difficult because of the centrality and the technical complexity of a transmission system.

The first issue discussed is the allocation of the costs of the transmission system, both fixed costs of transmission and costs that arise from the economic use of transmission. Next the paper discusses the management of transmission congestion and the treatment of losses. Even the simplest OATT needs to address either implicitly or explicitly the rights that are conveyed to those taking service under the OATT. Finally, the paper briefly discusses the treatment of ancillary services.

3 TRANSMISSION INFRASTRUCTURE REVIEW

The features and limitations of a given market structure depend heavily on the physical transmission system around which that system is organized. Thus, the pros and cons of alternative transmission market structures should be considered with the current system in mind since different market structures will stress the transmission system in different ways. While the short-term implication of a given market structure depend highly on the transmission system, in the long term the implications depend more highly on the market structure itself as new load and generation deplete existing transmission system surpluses.

The transmission system in Nova Scotia is fairly well developed and robust, comprised largely of radial 345 kV, 230 kV and 138kV lines connecting most of thegeneration in the East with the major load center in the Canso Strait area, Halifax and southwest. The 345 kV and 138 kV lines running north into New Brunswick at Truro form the major import and export paths out of the Province. A 69 kV circuit loops around the western part of the Province connecting hydroelectric generation and the sparse load.

Major bottlenecks within the system are infrequent at present and are usually limited to times when key generating or transmission facilities are out of service, or heavy export during light load periods. Due to their infrequency at present they are addressed more cost effectively through limited re-dispatch and generation rejection Special Protection Systems than through transmission expansion. The cost associated with these actions is small compared to overall cost of operating the system, and these minor costs are folded into bundled service rates paid by all customers.

Transmission reinforcements may be needed in the event that export opportunities and capability are significantly improved or for example, if significant new generation is added in the Eastern part of the Province where natural gas makes landfall, but existing east-west transmission is near its limit.

3.1.1 Nova Scotia Interconnections

NSPI is interconnected with New Brunswick through two parallel circuits, a 345 kV connection from Truro to Salisbury, NB, and a 138 kV line to Moncton which has a 200 MW tap at Memramcook to serve PEI. Although New Brunswick Power reports 550 MW of export capability on this interface, it represents the total of simultaneous exports to PEI plus Nova Scotia. On the other hand, the capability for Nova Scotia to import power is limited by the amount of load that would be shed by underfrequency load-shedding for a single transmission contingency, as well as the largest generation contingency in Nova Scotia. Exports are limited by the amount of generation that is practical to trip for a single contingency, while still honouring the reserve-sharing agreement with New Brunswick. Thus non-firm imports are limited to about 300 MW and non-firm exports to about 350 MW, with firm transfers limited to about 100 MW in each direction, depending on seasonal conditions.

4 Allocating The Fixed Costs of the Transmission System

One of the key decisions that will need to be made is how the fixed costs of the transmission system will be allocated. While, under a regulated utility structure, these costs are allocated to customers through some type of ratemaking process, several issues are raised as to the allocation of these costs, including the following:

- What transmission facilities will be covered under the tariff?
- What operating costs will be included?
- What billing determinants will be used to allocate these costs?
- Will the rate be paid by all transmission customers or only Nova Scotia loads?
- What proportion of costs will be allocated to market participants seeking to export power out of Nova Scotia?
- Will this rate component also be unbundled for existing service customers?

4.1 Transmission Facilities Covered Under the Tariff

As discussed in the June 28th Open Access Transmission presentation, FERC has concluded that there is no "bright line" separating transmission and distribution, upon which to judge which facilities and their costs to include in the Open Access Transmission Tariff (OATT). Although several principles for distinguishing these facilities are identified[1], FERC has held that the classification of facilities must be resolved on a case-by-case basis [need citation]. Since the costs of those facilities that are classified as transmission are included in the OATT rates and those that are classified as distribution are not, the classification of facilities as transportation or distribution may have an effect on the relative costs of bundled versus competitive wholesale service, as well as the economics of third-party exports.

Related decisions include the following:

- What facilities should be considered transmission facilities and what should be considered distribution facilities?
- Whether radial transmission used to interconnect new third-party cogeneration facilities should be included in the tariff.
- Whether radial transmission used to interconnect existing third-party facilities should be included in the tariff or directly assigned.
- Whether radial transmission for any generation connection should be included in the tariff or directly assigned.

4.1.1 Facilities to be Designated as 'Transmission Facilities'

The selection of facilities to be designated as transmission for the purposes of the OATT has consequences for the rates paid by those seeking to take service under the OATT. Since the municipal customers eligible to take wholesale service under the OATT have their own distribution system and their own imbedded costs associated with this distribution, both equity and FERC guidelines require separate accounting for distribution facilities. While the means of distinguishing distribution from transmission must be FERC compatible, the philosophy of this classification can lean toward inclusion or exclusion of facilities. There is also some leeway with respect to the classification of common facilities, including structures, automotive fleets, etc. Classifying a marginal asset as transmission will increase the total costs paid by OATT customers and decrease the total costs paid by bundled service customers. Since wholesale customers form a minor portion of the total load,

[1] These principles were specified in the presentation to the EMGC "Open Access Transmission" on June 28.

these costs will have a higher impact on OATT rates than on bundled service rates, although both rate impacts are likely to be small.

4.1.2 Including the Costs of Interconnection Facilities in OATT Rates

Depending on the geography of a region, radial connections to new generation facilities can be a significant component of the fixed costs of transmission paid by those taking service under the OATT. While bundled in-province loads served by remote generation use and should pay for any long radial transmission facilities connecting that generation to the load, there is a question of whether other competitive wholesale loads or 'through service' customers that are not accessing that remote generation should be exposed to those costs.

The question of interconnection costs allocation might be answered differently for transmission connecting new third-party generation facilities than for existing remote generation serving bundled load. The allocation of interconnection costs has a direct bearing on the cost of developing new generation at remote locations versus locations near the load. The two major alternatives include rolling these costs into the total OATT revenue requirement or directly assigning the cost of these facilities to the new generator. FERC generally favors the direct-assignment approach and has a Notice of Proposed Rulemaking (NOPR) currently out addressing exactly what constitutes interconnection, e.g. under what circumstances can breakers that need to be replaced when new generators are added be directly assigned to the generator. [2]

When the new generation is relatively small scale, such as some generation from renewables, direct assignment of transmission connection costs could become a major barrier to investment. This could be a consideration in the decision on whether to assign connection costs directly to new generation.

While sharing these costs has the advantage of accounting simplicity, directly assigning these facilities sends an economic signal for new generators to locate where fixed transmission costs are minimized.

While cost allocation for interconnection facilities ('connecting to' the system) is fairly straight forward, similar issues are raised for 'connecting across' the system. Intricately tied to broader market re-design issues such as the design

[2] FERC RM02-1-000 "Standardizing Generator Interconnection Agreements and Procedures". FERC 99FERC62,086. Web address http://rimsweb1.ferc.gov/rims.q?rp2~rimsdocinfo~2269318.

of a capacity market, responsibility for mitigating new congestion, and overall congestion management allocation, this issue can be developed further in later papers.

Direct assignment of these costs raises cost-sharing issues where multiple third party generators require reinforcement of the same transmission system.

New Brunswick directly assigns the cost of new transmission to the generator owner, and although it can and does pass these costs on to its customers, it does not pass them on to all customers. Hydro Quebec included most long radial connections to its remote generation in its OATT, increasing the cost of through service to customers outside of Québec[3]. New England assigns direct interconnection costs to new generators, but has relatively little transmission used exclusively to serve load from remote generation.

4.2 Transmission Operation and Maintenance Costs Included in the Tariff

Transmission (and distribution) operating and maintenance costs can be a significant (5-15%) component of the costs of running an integrated electric utility. The manner in which these costs are allocated can be a significant driver in the cost of service under the OATT. As the classification of facilities into transmission and distribution categories can be difficult, cleanly separating distribution maintenance costs from transmission maintenance costs can also be challenging. Administrative overhead and general costs need to be allocated to the generation, transmission, and distribution functions even where restructuring is limited to functional unbundling as contemplated under Order 888/889.

In some jurisdictions, the decision to separate ownership of generation, transmission and distribution has been driven in part by the ease and accuracy of allocating costs. Where appropriate these structural alternatives will be presented in future issues papers.

4.3 Billing Determinants for Fixed Transmission Cost Allocation

[3] This practice has been challenged. In its recent decision, the Régie de l'énergie required Hydro-Quebec's transmission arm, TransEnergie, to produce a cost study showing separately the cost of radial connection for generation, including Churchill Falls. Decision D-2002-95, 30 April 2002.

To define an OATT, a choice must be made as to how to evaluate a wholesale customer's use of the transmission system relative to its use by bundled service customers; thus, some metric for measuring that use must be selected. While two major alternatives, peak load (per MW allocations including monthly and annual peak load) and volumetric (per MWH) allocations are widely in use, other approaches to measuring transmission system use for allocating fixed costs may be considered [4].

4.3.1 Peak Load Allocations

The philosophy behind the peak load (per MW) allocation approach is that the transmission system has to be designed to accommodate peak loads, so customers with a high coincident peak load contribute more to transmission system cost than those with a smaller or less coincident peak load. In the extreme, the allocation of fixed transmission and O&M costs would be based on the ratio of that customer's annual coincident peak to the annual coincident peak of all customers.

From the wholesale customer's point of view this type of cost allocation has some of the following drawbacks:

- It varies from year to year even for a customer with a pattern of usage that does not change from year to year. As such it makes the comparison of bundled service versus wholesale service more difficult.
- It places a risk of significantly higher costs for customers who supply a portion of their own load (partial requirements customers) if their own generation is out of service at the time of the coincident peak.

The approach has some advantages in that it provides an incentive for municipal customers to manage their peak loads. In jurisdictions where there is a peak load allocation of cost, municipal systems often bill their customers by coincident peak load and manage their loads with an energy management system.

Other peak approaches step away from the coincident peak and move to annual or monthly wholesale customer peak, since these are easier to meter and produce less volatile transmission costs for the wholesale customer.

[4] See for example: "Review of Usage-Based Transmission Cost Allocation Methods under Open Access", EEI, April 2000 (PE-075PRS).

4.3.2 Volumetric Allocations

The volumetric approach (per MWH) avoids the need for calculating coincident peak contributions, avoids extreme charges for facilities supplying a portion of their own loads when their own generation is out of service, is relatively simple to meter, and is based on the notion that all customers using the system at any time should pay a share of the fixed costs. For example, while a hypothetical wholesale municipal customer using the transmission system every hour except during the system peak would pay no fixed costs under the coincident peak allocation, that customer would pay under the volumetric allocation in proportion to their overall use as a ratio to the overall use of all customers.

From the bundled customer's point of view volumetric allocations allow partial requirements wholesale customers to pay for less wire than is needed to support their system when the partial requirements customer loses internal generation; however, the wholesale customers envisioned for initial open access do not have significant embedded generators.

Currently both New Brunswick and New England use a peak load allocation. New York, by contrast uses a volumetric approach. FERC has asked in its options paper whether this feature of market design should be standardized or regional variation allowed.[5]

4.3.3 Other Allocation Approaches

Another volumetric possibility that is being developed, although it is not widely in use, does not allocate the combined revenues required for all transmission facilities as do the two previous methods, but rather allocates the costs of individual transmission facilities by their use. Thus, wholesale municipal customers that are located further from the generation serving their loads pay a larger share of transmission costs than do municipal customers located near their generation. This can be done either by disaggregating the costs of specific transmission facilities (those that are amortized would cost less) or by assuming that each mile of transmission used has the same cost (MW-Mile approach).

[5] FERC "Electricity Market Design and Structure – Notice of Options Paper" RM01-12-000, April 10, 2002 Web address http://rimsweb1.FERC.fed.us/rims.q?rp2~rimsdocinfo~2263854.

All generation and load pairs use the transmission system in accordance with the laws of physics. Every point-to-point transmission contract uses a unique set of transmission lines according to the impedance of those lines. This approach assesses the use of various transmission facilities and allocates the cost of that transmission to those transactions and loads in proportion to the capital cost and operating costs of the transmission in use. Customers would see charges posted for every point of injection and point of withdrawal and could make their procurement decisions accordingly.

While some argue that this is the fairest approach, some of the drawbacks of this approach include the following:

- It does not lend itself well to peak load allocations since a customer could game the system by having a different (lower use) contract to serve it peak load.
- It requires a separate accounting of transmission costs, costs that are not often kept separately for individual transmission lines.
- It is not widely used in part because it changes the allocation of transmission costs from the volumetric or peak load allocations adopted initially in other jurisdictions (not a consideration for Nova Scotia) and thus would cause cost shifts.

Advantages include the following:

- It explicitly addresses which facilities to include since it allocates the costs of all facilities to those that use them, including through service customers.
- It protects through-service revenues (not a consideration for Nova Scotia).
- It provides a framework for merchant transmission development (also not a consideration for Nova Scotia) by allowing for the recovery of fixed costs of new merchant transmission lines that are used.

4.4 OATT Rate for Nova Scotia and Exports

Two major alternative approaches to allocating fixed costs of transmission include allocating the costs to all users of the transmission system and allocating those costs only to the loads in Nova Scotia. While allocating the costs to loads only increases the costs that loads pay, it has some significant advantages when it comes to integrating with other systems. The consideration of the load-only allocation is part of the FERC Standard Market Design initiative and is largely done to address a standard means of allocating

costs. It has the disadvantage of sending the incorrect signal for transmission expansion since loads could see an increase in costs for new transmission that is used primarily for through service. If adopted region-wide it lowers the cost of exports and wheels through outside systems. The New Brunswick OATT currently allocates a portion of their system's fixed costs to through services customers. Absent a change in their system it is unlikely to be advantageous for Nova Scotia to unilaterally adopt such a system.

4.5 Cost Allocation OATT to Export Customers

If it is decided that all wholesale customers should pay for transmission system use, there is a question of how the costs of transmission facilities connecting the Province to outside areas should be allocated. Alternatives range from including these transmission facilities in the average rate paid by all transmission users, to allocating these costs directly to those importing or exporting power. Since most of the power imported as well as most of the power exported serves bundled service customers, a separate allocation will increase the proportion of costs paid by bundled service customers compared to wholesale customers served by generation within the Province. There is also a strategic question as to whether it is a competitive advantage to have a lower cost to export power.

4.6 Unbundling Transmission Cost for Existing Bundled Service Customers

To define an OATT, it is necessary to decide to whom that OATT applies. The fundamental choice is whether the OATT applies to all customers including those who currently take bundled service or only to eligible wholesale customers. This is not to imply that other customers will have open access, only that the component of their currently bundled electric rates will be disaggregated on their bill, so that the transmission component of their bill is transparent to all customers. Deciding to include only eligible customers in an initial OATT implementation will not foreclose the option of unbundling rates paid by other customers in the future.

Although unbundling rates can create additional accounting work and expense, it also serves as a means of communicating to bundled service customers the portion of their bill that would be subject to competition if they became eligible. These customers could then distinguish the potentially competitive part of their bill (the power supply component) from those charges

that they would pay whether they took competitive service or not (OATT charges and distribution charges). Unbundling of rates is therefore an important transitional step if the ultimate objective is broad or universal open access.

5 APPROACH TO CONGESTION MANAGEMENT

The approach to congestion management is a fundamental choice in the design of an electric market. While the treatment of congestion can range from an implicit continuation of the current methods to a complete restructuring of congestion allocation, designing an OATT does not require congestion management changes. Although not necessary for designing an OATT, several approaches to congestion management are introduced here and can be developed, if appropriate, in further issues papers.

Congestion arises when the transmission system limits the amounts of energy that can be transferred from one location to the next. This results in resources that are more expensive than the least expensive being dispatched to serve load. In Nova Scotia, these costs are currently infrequent and relate primarily to times when key facilities are out of service, although they can become more frequent and severe if new generation is added in locations where it does not minimizes congestion. The interconnection with New Brunswick has unique characteristics considering the radial topology of the Nova Scotia Power system – a single 345kV contingency can create an electrical island requiring either load or generation to be shed for system security.

An OATT could, in theory, continue the current sharing of congestion costs. The FERC Order 888 Proforma Tariff addresses transactions that require re-dispatch of generation to be feasible. The proforma tariff allows the host utility to curtail any transactions that cause re-dispatch costs but if requested (and paid) by those seeking service to study and identify re-dispatch costs arising from the requested transaction. Wholesale customers agreeing to pay these re-dispatch costs can continue to receive service. The advantage of this approach is that it is consistent with both the FERC Proforma and the current New Brunswick OATT.

5.1 Treatment of External Transactions

Although congestion within the Nova Scotia system is manageable and infrequent, the limited firm capacity of the intertie with New Brunswick will create unique challenges for importing and exporting under the OATT. Rules

should be carefully crafted to assure that no inappropriate incentives are inadvertently created to site facilities outside of the province when it would otherwise be less expensive to site them within the province. It is also appropriate that the cost of congestion outside of Nova Scotia not be borne or shared by Nova Scotia customers, unless they benefit significantly. Thus even if a simple approach to congestion management is adopted within the province, the treatment of congestion related to external transactions warrants a detailed review. In addition, issues with the allocation of external capability arise where there are existing firm contracts for the use of a portion of that capability, or where new competing uses are vying for that same capability.

One policy decision that should be made is the extent to which congestion associated with imports and exports of power should be paid by the transaction requester. This decision can be made independently of the decision as to how to allocate congestion costs within the Province.

In the current New Brunswick tariff, for example, priority is given to existing contracts, with no transactions that create additional re-dispatch costs allowed (unless paid for by the requester). Remaining available transmission capability (ATC) is allocated on a first come first serve basis with longer transaction requests and those creating higher net present value revenues taking priority over shorter requests. To continue to receive priority, shorter requests that are granted have a responsibility to match the term of a longer request that is subsequently received.

5.2 Long Term Congestion Management Choices

Several major alternative approaches for managing congestion have been devised and are in use in markets in North America and throughout the world.

Although paying generation a market price that reflects congestion at each location (LMP or locational marginal pricing) is used in many markets throughout North America, this approach is generally inconsistent with the wholesale bilateral-only type market envisioned for Nova Scotia. Approaches consistent with a bilateral-only type market include the following:

1. Create a Single Transmission Pricing Zone - Add Both Congestion Costs and transmission expansion costs to transmission rates paid by all loads

(e.g. Ontario IMO);

2. Create a Single Transmission Pricing Zone - Add congestion costs to firm transaction transmission costs but require new third-party generators to pay for transmission expansion to prevent new congestion costs (e.g. ISO-NE);

3. Flow Gate Approach – Assess re-dispatch costs to bilateral transactions that cause congestion on limited transmission facilities. Grant rights to avoid these costs to existing customers and those expanding the capability of these facilities. (e.g. Mid-West RTO).

4. Create an LMP Market – Not needed to implement an OATT, this approach can accommodate multiple generator owners and eligible loads bidding to use the transmission system. Favored by FERC for its standard market design and in use throughout the Northeast US, this approach creates a price at each location that reflects congestion.

Congestion management alternatives will be described in detail in further issues papers. Wide scale restructuring of congestion management warrants considerable consideration, which could be done subsequent to the adoption of an interim OATT.

6 TREATMENT OF LOSSES

Losses are currently bundled with the cost of power paid by all loads. As some loads become eligible to obtain wholesale service, the question of how to allocate losses becomes important. Major approaches include the average loss and marginal loss approaches. The average loss approach involves determining the total system losses and sharing these among all customers on a MWh basis. The marginal loss approach involves calculating losses associated with the requested wholesale transactions and allocating the cost of those losses to the transactions. Other questions include whether the losses must be made up in kind through those requesting service supplying more energy than they receive, or whether the cost of system resources supplying losses could be calculated and allocated.

In the New Brunswick tariff, real power losses are identified by path and are allocated to the transaction causing the losses. NERTO is moving to dynamically calculating marginal losses by location, while other jurisdictions

simply average losses and allocate them to all customers, including both bundled retail and wholesale customers.

7 RIGHTS CONVEYED

One of the things that an OATT does or can do is to convey rights to the transmission system. Although this is related to the overall market structure and congestion management approach, a primary choice is whether the rights conveyed are physical or financial. Physical rights give the owner the right to move power from a given point to a given point in exchange for a payment. Financial rights, on the other hand give the owner the right to inject power at one location and withdraw the power at another location without paying congestion. Financial rights are associated with an LMP market structure. Who may request and pay for an expansion of the transmission system, as well as what rights they receive for that expansion, is an important aspect of market design. Although no change in transmission system expansion authority is required to implement an OATT, the Proforma requires the host utility to identity the costs of transmission expansion (if a customer is willing to pay for the study) and expand the system (if a customer is willing to pay for the expansion.)

8 TREATMENT OF ANCILLARY SERVICES

For the majority of ancillary services discussed previously the major OATT question is whether the particular ancillary service must be procured from NSPI or whether customers are allowed to self supply the resource. One alternative is to start with central provision of these services and allow customers to request self supply to be evaluated on a case-by-case basis.

One particular ancillary service (Balancing Service) requires a design decision. Balancing Service charges arise when a wholesale supplier supplies more or demands more power than it schedules for a transaction. For example, an eligible wholesale customer might indicate that it intends to move ten MWs of power from a remote location to the load. That customer might have a load of 10 MW as expected but its generation may be capable of only 9 MW of output, for example if part of the facility was forced out of service. Absent

other provisions, the energy deficit would be filled by system resources. The major alternative approaches to balancing service include the following:

- Provide the power but charge the eligible customer a penalty,
- Provide the power at marginal cost.

One approach is to charge deficiencies from scheduled loads a large penalty to provide them with an incentive not to under-schedule. For example, although it is currently under revision, in the NB tariff loads under-predicting the amount of power that they demand must pay $100/Mwh while those over-predicting receive only $18/MWh. Thus, there is a strong incentive to correctly predict the amount of load scheduled for delivery..

Another alternative, usually arising in markets that set a marginal clearing price or locational marginal price is to charge a balancing charge based on the cost of providing the next MW of power. Even systems that do not have a bid-based market often have a cost-based marginal price that is an output of their dispatch and scheduling software. This approach does not create an incentive for eligible customers to schedule accurately, and thus could result in costs (such as the starting of a combustion turbine) that might not have been incurred had the load been known in advance. It simplifies the job of the eligible customer that might have difficulty accurately predicting its load.

Other tariff issues include whether the ancillary services will be market based, whether loads will be able to self-supply these services, and whether the host utility will make these available or force bilateral buyers to procure the services on their own. The basis for calculating the amounts of ancillary services, such as operating reserves also should be considered especially for interruptible customers, behind the fence generators, and those exiting the system.